

TECHNOECONOMIC ANALYSIS OF HYDROGEN PRODUCTION FROM WESTERN COAL AUGMENTED WITH CO₂ SEQUESTRATION AND COALBED METHANE RECOVERY

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ABSTRACT

Hydrogen production via gasification of low sulfur western coal is being evaluated in a joint effort between the National Renewable Energy Laboratory (NREL) and the Federal Energy Technology Center (FETC). This work differs from past evaluations because it focuses on sequestering CO₂ and recovering coalbed methane. The off-gas stream, containing primarily CO₂, which is produced during hydrogen purification is used to displace methane from unmineable coalbeds. This methane is then utilized within the gasification-to-hydrogen system. Several processing schemes are being evaluated for maximizing hydrogen production or co-producing hydrogen and electricity. A combination of the following process steps are being used in these analyses: coal gasification, gas clean-up, shift conversion, hydrogen purification, hydrocarbon reforming, power generation, and hydrogen storage and transportation. The lowest cost storage and delivery method will be determined based on several factors including production rate, transport distance, and end use. A discussion of the cases being studied is presented.

INTRODUCTION

A collaborative effort to study the feasibility of producing hydrogen from low Btu western coal with an emphasis on CO₂ sequestration and coal bed methane recovery is being undertaken. The researchers at FETC are using their expertise in the field of coal gasification along with their existing models to examine coal gasification and gas clean-up. Because of extensive past technoeconomic analysis in the areas of hydrogen production, storage, and utilization NREL is examining the process steps associated with these operations using their previously developed models. Both parties are working to analyze CO₂ sequestration and coalbed methane recovery along with the possibility of power co-production. The models are being updated and integrated to incorporate the details of each system design as well as to account for the heat integration of the overall system.

COAL ANALYSIS

Wyodak coal was selected as a suitable coal that meets the needs of this study. This is a low rank Western coal that is inexpensive to produce and is available in an abundant supply. Additionally, the state regulations in Wyoming permit the extraction of coalbed methane making this site attractive for CO₂ sequestration and coalbed methane recovery. The elemental analysis and heating value of the Wyodak coal used in this work can be seen in the following table (EIA, 1995).

Table 1: Wyodak Coal Analysis

<u>Ultimate Analysis</u>	<u>(Weight %, dry basis)</u>
Carbon	67.6
Oxygen	17.7
Hydrogen	4.8
Nitrogen	1.2
Sulfur	0.8
Ash	7.9
Moisture, as-received (wt%)	26.6
Heat of combustion, HHV, as-received	20,073 J/g (8,630 Btu/lb)

GASIFIER TECHNOLOGY

The Destec gasifier which is a two-stage entrained, upflow gasifier is being used for this analysis. The gasifier is currently being demonstrated under FETC's Clean Coal Technology Program at the Wabash River Coal Gasification Repowering Project in West Terre Haute, Indiana. The gasifier operates at a temperature of 1,038 °C (1,900 °F) and a pressure of 2,841 k Pa (412 psia). For hydrogen production the gasifier must be oxygen blown in order to minimize the amount of nitrogen in the syngas. Nitrogen is a strongly adsorbed component in the pressure swing adsorption (PSA) unit and will reduce the hydrogen recovery rate even at low levels. The feed is a coal/water slurry containing 53 wt% solids. The following is the syngas composition exiting the gasifier:

Table 2: Syngas Composition

Component	N ₂	Ar	H ₂	CO	CO ₂	H ₂ O	CH ₄	H ₂ S	NH ₃	COS
mol %	0.6	0.7	27.7	27.4	16.5	26.6	0.0939	0.1399	0.2	0.0061
Heat of combustion, HHV, = 419 J/g (180 Btu/lb)										

From the composition listed in Table 2 it is apparent that reforming of the syngas for hydrogen production is not necessary because the gasifier produces only a trace amount of hydrocarbons. However, in order to maximize hydrogen production, one or more shift reactors will be needed to convert the carbon monoxide to hydrogen.

HYDROGEN PRODUCTION OPTIONS

Two options are currently being evaluated: Option 1 is maximum hydrogen production and Option 2 is co-production of hydrogen and power with the hydrogen being produced from the syngas and the power from recovered methane. See the simple block flow diagrams shown in Figures 1 and 2. The shaded blocks are the process steps that differ between the two options. Time permitting, other options for co-production of hydrogen and power will be tested in the future. In order to compare the economics as well as the overall CO₂ emissions from each option, the base case analysis will include only the process steps associated with coal gasification, shift, and hydrogen purification (i.e., none of the steps associated with CO₂ sequestration or coalbed methane recovery will be included in the base case). All of the options studied in this joint venture will be compared to this base case.

Figure 1: Option (1) - General block flow of maximum H₂ production

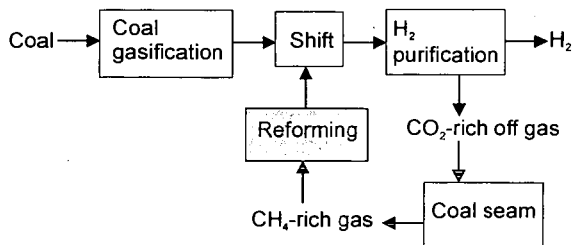
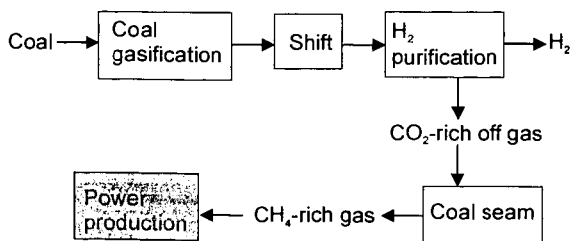


Figure 2: Option (2) - General block flow of H₂ Production from Syngas and Power Production from Recovered CH₄



HANDLING SULFUR IN THE SYNGAS

Because the syngas from the gasifier contains approximately 1,400 ppm of H_2S several schemes for handling the large sulfur concentration are being examined to determine which will be the most economical. Four potential schemes have been configured and are depicted in the drawings below (Figures 3 - 6). The dashed boxes contain the process steps which are different between the four schemes. Overall heat integration is not shown in these figures.

For the ZnO bed, the inlet H_2S concentration needs to be in the 10-20 ppm range. The high temperature shift (HTS) catalyst can tolerate concentrations up to 200 ppm but typically operates at lower levels whereas sulfur is a poison for the low temperature shift (LTS) catalyst and thus the H_2S needs to be reduced to a level below 0.1 ppm. Shift catalyst manufacturers produce a "dirty" shift catalyst which requires a sulfur concentration of at least 200 ppm in the inlet gas. Depending on the regulations for injecting sulfur into the ground, scheme 3 which does not remove the sulfur from the syngas, may not be a possibility. Also, note that there is not a scheme which incorporates the dirty shift catalyst with sulfur recovery via HGSU because HGSU would always be used prior to the shift reactors.

Figure 3: Sulfur scheme (1) - regular shift catalyst with hot gas clean up (HGSU)

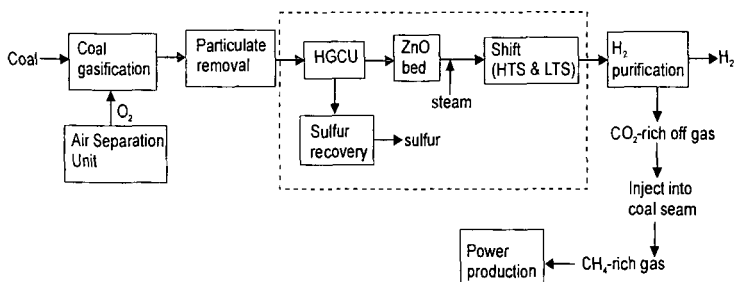


Figure 4: Sulfur scheme (2) - regular shift catalyst with cold gas clean up

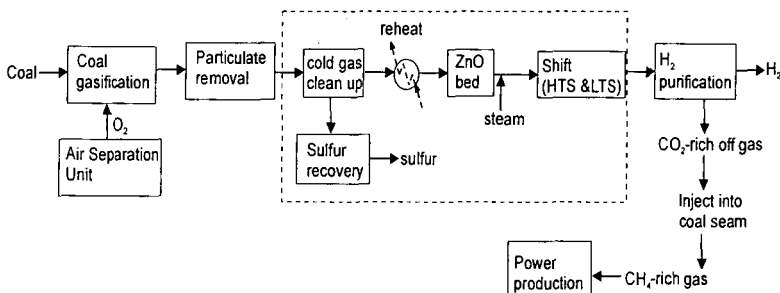


Figure 5: Sulfur scheme (3) - dirty shift catalyst with no sulfur recovery

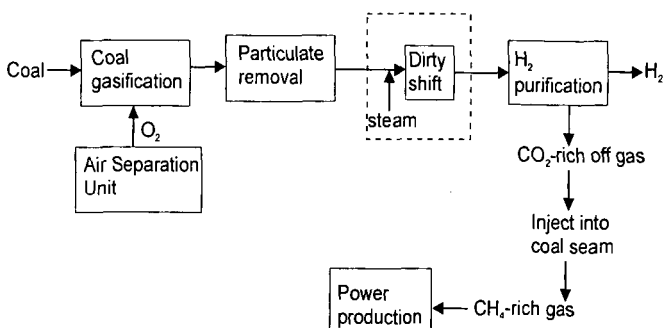
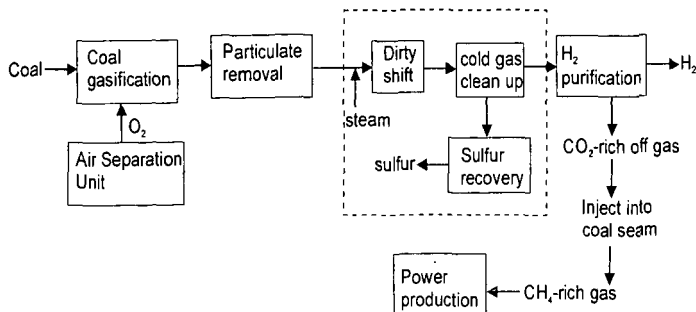


Figure 6: Sulfur scheme (4) - dirty shift catalyst with sulfur recovery via cold gas clean up



The coal gas leaving the gasifier contains entrained particles of char and ash. Particulate removal will be performed through cyclone separators and ceramic candle type hot-gas filters. Hydrogen purification will be done using a PSA unit. Because this unit operates at a pressure considerably lower than the coal seam, the off-gas must be compressed prior to injection.

CO₂ SEQUESTRATION AND CH₄ RECOVERY

Based on data from previous studies (Gunter *et al*, and Hendriks, 1994) this analysis assumes that two molecules of CO₂ are being injected for every one molecule of CH₄ released from the coalbed. This is based on worldwide data which shows that on average a little more than twice as much CO₂ can be stored in a methane field, on a volumetric basis, than the amount of CH₄ extracted. The off-gas from the hydrogen purification unit which contains primarily CO₂ (about 68 mol%) must be compressed from 2.7 MPa (392 psi) to a pressure of 3 - 14 MPa (500- 2,000 psi) which is the pressure range generally found in coalbed methane reservoirs (The American Association of Petroleum Geologists, 1994). Compressing the off-gas will require a significant amount of electricity. To adequately determine the overall reduction in CO₂ emissions for each option studied, the CO₂ emissions associated with electricity production must be added to the overall CO₂ balance of the system. Therefore, the net reduction in CO₂ will actually be less than the amount of CO₂ captured in the off-gas from the PSA unit. Additionally in the case of co-production of power, any CO₂ emitted during this process step must be included in the overall CO₂ balance to get a complete picture of the reduction in CO₂ emissions.

STORAGE AND TRANSPORTATION

In order to determine the effect of hydrogen storage and transport on the delivered cost of hydrogen, the following scenarios are being examined and incorporated into the analysis:

- (1) bulk delivery:
 - 16 km (10 mi) one-way
 - 160 km (100 mi) one-way
 - 1,610 km (1,000 mi) one-way
- (2) on site consumption: 12 hours of storage; no transport.
- (3) gas station supply: weekly hydrogen delivery; driving distance of 160 km (100 mi) round trip; supplying multiple stations along the way; hydrogen use of 263 kg/day (580 lb/day) per gas station.
- (4) pipeline: 3 km (5 mi) to the nearest pipeline infrastructure; no storage; an additional 160 km (100 mi) pipeline for hydrogen delivery to end user for which the cost is shared by 5 companies.

The cost of storing and transporting hydrogen depends on the amount of hydrogen the customer needs and how far their site is from the production facility. The most economical mode of storage and delivery (i.e., liquid, compressed gas, metal hydride or pipeline delivery) will also vary depending on production rate and distance. For example, while liquid hydrogen delivery is one of the cheapest methods of transporting hydrogen long distances, it requires a large capital investment for a liquefaction facility and there can be significant transfer losses during loading and unloading. This large capital investment at the production site, along with product losses, can make another method of delivery more cost effective.

The above cases represent four likely scenarios for hydrogen use. In each case, the cheapest delivery and storage method will be identified, along with the associated incremental cost that must be added to the production cost to get the total delivered cost of hydrogen. The technoeconomic analysis for this work will be completed this fall.

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